Negative electricity market prices

Recent observations show that European electricity market prices turn negative when high shares of inflexible generation hit a low demand. The increasing share of Renewable Energy Sources for Electricity (RES-E), such as wind and solar Photovoltaic Power (PV), is an important driver due to the intermittency of its energy source[1]. The objective of the factsheet is to explain this phenomena of negative prices, as well as the behaviour of electricity markets with high shares of RES-E.

Table 1 represents the national statistics of leading EU member states in terms of the installed capacities of wind and solar power by the end of 2012. In Belgium, both technologies accounted for 3.4% and 1.9%, respectively in terms of average electric energy penetration. Concerning wind power integration, lessons can be learned today from leading countries such as Denmark (30.0%), Portugal (20.4%), Spain (18.2%) and Ireland (15.6%). For solar power integration, leading countries are Italy (5.7%), Germany (5.1%) and Spain (4.3%).

In terms of power ratios, these shares of variable RES-E may account for "maximum penetrations" exceeding 100% of the minimum demand. Table 1 shows how this may already be the case for wind power in Denmark (200.0%), Portugal (127.3%), Spain (126.6%) and Ireland (100.0%), when expressing the installed capacity relative to the minimum consumption level. The maximum penetration is an indicator for the need for curtailing part of the renewable capacity, for export or for storage. Meanwhile, the shares of RES keep on growing under the effect of policy targets and declining investment costs. For instance in Belgium, wind power and PV have grown respectively up to 1.7 and 3.0 GW towards the beginning of 2014.

Historically, system operators, regulators and policy makers were mainly concerned about upward adequacy, i.e. the ability of power systems to meet peak demand and avoid demand shedding. This topic remains certainly relevant today, especially where power systems face decommissioning of older power plants, in countries where a nuclear phase-out is decided, while existing units with high marginal cost (such as gas-fired generating units) face problems maintaining their profitability. In combination with intermittent RES-E, this leads to an increased risk for periodical shortages[2]. However, attention is also needed for downward adequacy, i.e. the ability of the system to cope with low demand periods. Recent events have shown that system inflexibilities may lead to periods with excess power, challenging the operation of the power system. These inflexibilities include renewable generation dealing with priority dispatch and production support mechanisms, conventional generation facing techno-economic limitations in output variations, and must-run conditions of power plants for system security reasons.

This issue is referred to as the "incompressibility of power systems" and is recently observed in Central Western European electricity markets such as Germany, France and Belgium, with hours showing negative electricity prices on day-ahead, intra-day and balancing markets. Economic theory imposes that low demand together with a large

Table 1: Installed capacity (GW) and annual electricity generation (TWh) of wind and PV in selected European countries by the end of 2012 (based on data published by ENTSO-E 2013)

	wind				solar (mostly PV[3])			
	GW	TWh	penetration [%]		GW	TWh	penetration [%]	
			mean[1]	max[2]			mean[1]	max[2]
Denmark	4.2	10.3	30.0	200.0	0.4	0.0	0.0	19.0
Portugal	4.2	10.0	20.4	127.3	0.2	0.4	0.8	6.1
Spain	22.4	48.5	18.2	126.6	6.1	11.6	4.3	34.5
Ireland	1.6	4.0	15.6	100.0	n.a.	0.0	0.0	n.a.
Germany	30.9	46.0	8.5	96.3	32.8	27.6	5.1	102.2
Italy	8.1	13.3	4.1	38.6	16.4	18.6	5.7	78.1
Belgium	1.3	2.9	3.4	21.0	2.5	1.6	1.9	40.3

[1] average electric energy penetration: annual electricity generation in terms of total consumption; [2] max penetration: installed capacity in terms of minimum consumption; [3] solar in Spain includes 2.0 GW Concentrated Solar Power (CSP)

[1] Intermittency refers to the limited controllability and partial predictability of a generation resource.

[2] Energy Institute KU Leuven "Factsheet Security of Supply" September 25, 2013 http://www.kuleuven.be/ei/

supply at nearly-zero marginal cost results in lower market prices. However, events with negative prices are less straightforward as these price levels translate into generating units which are willing to pay for the consumption of electrical energy.

Negative day-ahead market prices

Figure 1 represents the theoretical framework of the impact of renewable power with low variable cost in day-ahead wholesale electricity markets. In this market, electricity is traded and positions are taken for the next day, based on the market expectations. The supply curve is represented by a merit order of generation technologies, representing their marginal generation cost. Usually, but depending on the actual fuel costs, these generation technologies are categorised as base load (e.g. nuclear and coal-fired power plants), mid load (e.g. combined-cycle gas turbines) and peak load (e.g. open-cycle gas turbines, diesel engines). The price is set by the intersection of the demand curve and the supply curve. In Figure 1 (left), it is shown that the expected demand impacts the price of electricity. A low demand does not require the activation of the more expensive power plants and results in a lower price. Furthermore, when a certain injection of RES-E is predicted with an almost zero marginal cost, the supply curve is shifted to the right, lowering the electricity prices (Figure 1, right), referred to as the merit-order effect. This results in price volatility as these RES-E are characterised by an intermittent availability.

However, due to technical constraints of power systems, the supply curve may look different in reality. Certain generation technologies such as older nuclear power plants in some countries are not designed for short-term output variations (referred to as inflexible base load). Furthermore, part of the conventional power plants has to remain on-line for security reasons, such as providing reserve capacity, paid for by the TSO (referred to as must-run generation) (See Figure 2, left). This issue becomes even more important with the increasing share of RES-E facing prediction errors and additional reserve capacity requirements. This may result in negative price bids, in order to guarantee the acceptance of this bid. Furthermore, RES which actively participate in the market, can bid negative prices due to the presence of support mechanisms. They are willing to generate as long as the negative electricity price is compensated by the production support under the form of feed-in tariffs or green certificates (Figure 2, right). Part of the operation of RES which is market-price insensitive due to priority dispatch policies or control difficulties following its distributed generation (DG) nature, as for instance local PV generation in Belgium, are treated as negative demand, shifting the demand curve to the left (Figure 2, right).

This explains how prices can turn negative when facing low demand together with high RES injections. It is currently observed that negative price periods on European day-ahead markets increase in frequency. In the last week of December 2012, a low demand in the holiday period together with a high wind

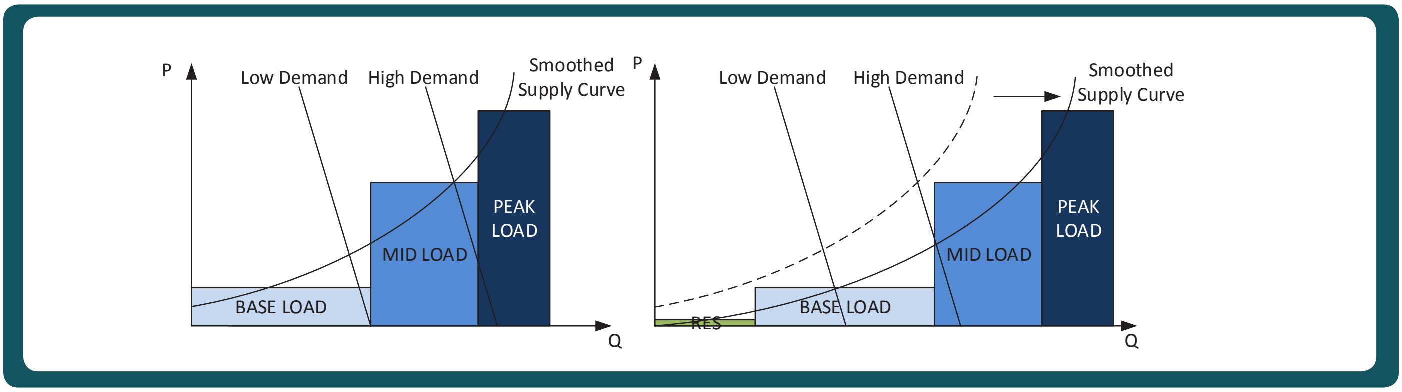

Figure 1: Theoretical merit order without (left) and with renewable energy sources (right)

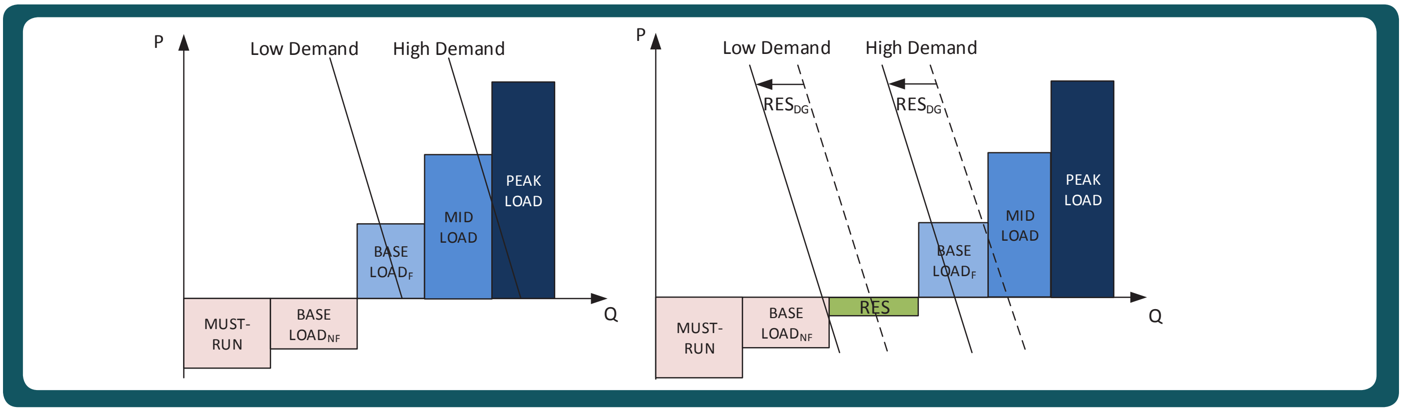

Figure 2: Practical merit order without (left) and with renewable energy sources (right); RES$_{DG}$ expected renewable generation production of distributed nature; F flexible; NF non-flexible

situation resulted in negative prices on the day-ahead hourly electricity market for Germany and Austria (EPEX Phelix). Negative day-ahead prices down to -222 €/MWh were registered during the night of December 25th, and this problem reoccurred multiple times during the rest of that week.

A similar event occurred in Central-Western European region, i.e. Belgium, Germany and France in the weekend of June 15-16, 2013 facing a regional low industrial consumption on Sunday, low residential consumption on mild weather, and abundant inflexible generation driven by wind, PV, hydro and nuclear[3]. In France, a daily average price of -41 €/MWh and -20€/MWh (EPEX), respectively, for base and peak demand periods on the day-ahead market, and minima down to -200 €/MWh during the night were observed. As the day-ahead electricity markets of France, Germany and Belgium are coupled, these prices are buffered and spread over the region, constrained by the available interconnection capacity. This was, for instance, the case for the same weekend discussed here, where average prices in Germany/Austria (EPEX Phelix) fell to roughly -20 €/MWh and 3€/MWh for respectively peak and base demand periods, and minima down to -100 €/MWh.

Prices also turned negative on the Belgian day-ahead market (Belpex) that same weekend as the price hit a low of 200 €/MWh (Figure 3). The residual Belgian demand seen by the market participating generating units is low due to low demand and high RES penetration. This demand incorporates distributed wind and PV, which is treated as negative demand. A minimum demand of 6.2 GW was observed on Sunday, combined with a maximum of 2.6 GW of wind and PV on Saturday. The negative price peaks are explained by the must-run conditions of conventional power plants, the available nuclear capacity of 5.4 GW, and constrained export capabilities. Events where day-ahead market prices turn negative are still rare: in France in 2012, 56 hours with negative prices were observed in the French day-ahead market (EPEX), and these occurred over 15 days. In 2012 and 2013 in Belgium (Belpex), 7 and 15 hours were observed, respectively, in both cases for 3 days. As they are linked to low net demand periods, such events are expected to increase in frequency.

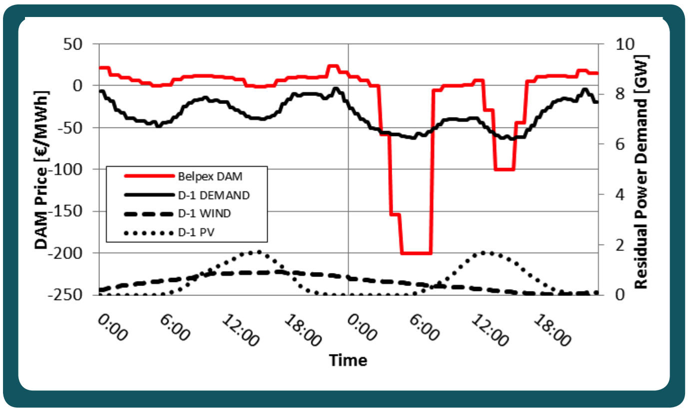

Figure 3: Belgian Day-Ahead Market Operation June 15-16 June 2013 (data: Elia System Operator and Belpex Power Exchange)

[3] APX, Belpex, EPEX SPOT - Joint Statement on negative prices in Belgium and France on 16 June 2013, http://www.belpex.be/

Negative intra-day market prices

In European power systems, market players are able to adapt their positions intra-day, based on updated market expectations. This is particularly useful for intermittent RES-E, relying on higher forecast accuracy closer to real time. This market is well represented in European power exchanges, matching bids on a continuous basis. In general, intra-day markets follow the same economic principles as day-ahead markets, although liquidity may be lower and prices more volatile. This is explained by technical limitations of generating units to alter their injections closer to real time. A trend towards European regional market coupling is present, which is expected to increase market liquidity. Prices in the intra-day market are related to the day-ahead prices and real-time balancing-market-price expectations.

In the case of December 25th, 2012, EPEX intra-day market prices were found to hit a low of 500 €/MWh in Germany/Austria. Also on June 15-16th, 2013, negative prices were observed on Belgian, French and German intra-day markets. In the French intra-day market (EPEX) in 2012, 41 hours with negative prices were observed, which occurred during 10 days. In the Belgian intra-day market (Belpex) in 2012 and 2013, 1 and 26 hours during 1 and 10 days were identified, respectively. It is to be noted that the intra-day market in Belgium remains relatively small and illiquid compared to the day-ahead market markets.

Negative balancing market prices

Real-time deviations from the scheduled market positions are dealt with on the balancing market. Historically, such deviations include unplanned power-plant outages and unexpected demand variations. With the increasing penetration of intermittent RES-E, also prediction errors result in an additional demand for balancing actions. Due to its strong relation to system security, this market is coordinated by the TSO. It contracts reserve capacity which is, today, mainly procured from conventional power plants, and can be quickly activated in real-time to cover system imbalances. In principle, a minimum amount is contracted by means of long-term contracts in order to keep a minimum capacity available. Furthermore, market players can offer additional capacity by means of short-term contracts which are closed one day before the real-time. Together, this results in a merit-order representing the activation cost of reserve capacity (Figure 4, left).

When activating upward reserves for the situation in which the system faces an instantaneous power shortage (negative imbalance), this results in a positive marginal price (MP) for balancing, and the TSO pays the Balancing Service Provider (BSP) (Figure 4, left). This activation price covers, inter alia, the fuel cost of increasing the output of the power plant. In Belgium, upward reserve capacity is provided with different mechanisms: the system imbalance is netted with other control zones by means of International Grid Cooperation and Control (IGCC). Upward fast-response secondary reserves (R2) include contracted and possible free bids from power plants. The slow-response tertiary reserves (R3) contain contracted and free bids from power plants, contracted bids from interruptible demand, contracted bids from resources on the distribution level (as of 2014), and a non-guaranteed emergency capacity from other TSOs.

In contrast to the upward reserve, the downward activation price can be positive or negative. Usually, the price is negative and refers to a payment of the BSP towards the TSO. This is explained by the fuel savings following the output reduction of a power plant. However, market players may also bid positive activation prices, i.e. willing to be paid for the activation. This may compensate power plants facing expensive shut-down costs, or renewable power plants losing production support. In this case, the imbalance settlement tariff becomes negative and money flows represented in Figure 4 (right) are reversed. In Belgium, downward reserve capacity is provided by means of the IGCC mechanism, secondary reserve, free bids and inter-TSO emergency.

The reservation and activation of reserve capacity are referred to as the procurement side of the balancing market, i.e. the reserve market. Reservation costs are included in the transmission tariffs and activation costs are transferred to the responsible market players by means of the imbalance settlement mechanism. In 2012, a one-price settlement system was introduced in Belgium (Figure 4, right). This represents the settlement side of the balancing market resulting in a price quoted on this market every quarter of an hour. An additional component is added when facing large imbalances, pulling apart the MDP and MIP price, and providing an additional incentive for BRPs to balance their position. Although the price is unknown in real-time, estimates can be made from the real-time system imbalance, the available capacity and marginal price published by the TSO. Balancing Responsible Parties (BRPs) can actively adapt their positions in order to minimise their imbalance volume or cost.

A first example of negative imbalance prices can be found in Germany where on February 10, 2013, PV injections were underestimated due to melting snow. This resulted in a downward reserve activation and negative imbalance prices down to -218 €/MWh. When studying time series of the Belgian imbalance tariffs for 2012 and 2013, it is found that negative prices are recorded 9.1% and 6.6% of the time, while minima were registered at -238 €/MWh and -313 €/MWh, respectively. An example of negative Belgian imbalance prices is found on April, 1, 2013 (Figure 5): large negative activation prices were recorded in the day-time, indicating an excess of power and providing a strong market incentive to reduce injection or increase off-take. This event is again caused by incompressibility where downward flexibility is limited in periods with low demand, resulting in negative pricing when facing high positive system imbalances.

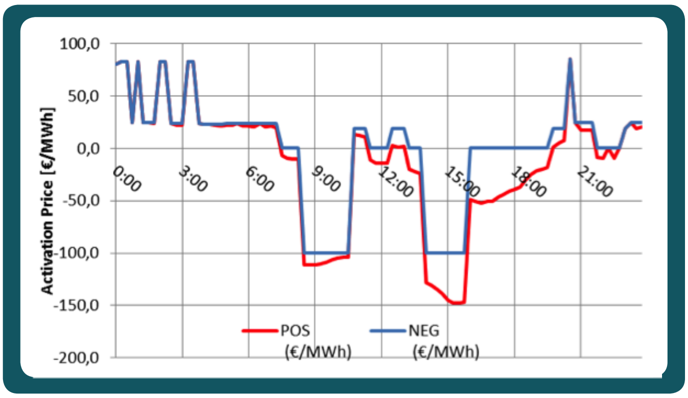

Figure 5: Imbalance settlement tariff on Belgian electricity market on April 1, 2013; POS positive BRP portfolio imbalance tariff (excess energy), NEG negative BRP portfolio imbalance tariff (shortage). A postive tariff means that the BRP with a negative imbalance pays the TSO and the BRP with positve imbalance is paid by the TSO. This is reversed in case of a negative tariff.

When studying the day-ahead market (Figure 6, left), it is confirmed that expected residual demand is relatively low resulting in lower prices during the day. It is noticed how this coincides with high values of predicted RES production during the day. Part of this production, i.e. the injections at the distribution level, is already included in the demand. A low demand results in fewer power plants scheduled, or scheduled at minimum load, resulting in little or expensive flexibility to cope with positive forecast errors. This translates into expensive downward reserve capacity. But evidently, and unfortunately, a large positive imbalance is correlated with the demand forecast error, the RES forecast error and the final PV injections (Figure 6, right). The main source of this imbalance is PV is integrated in the distribution system by means of 'netmetering', i.e. without direct metering of the PV injections, and therefore difficult to monitor, predict or control.

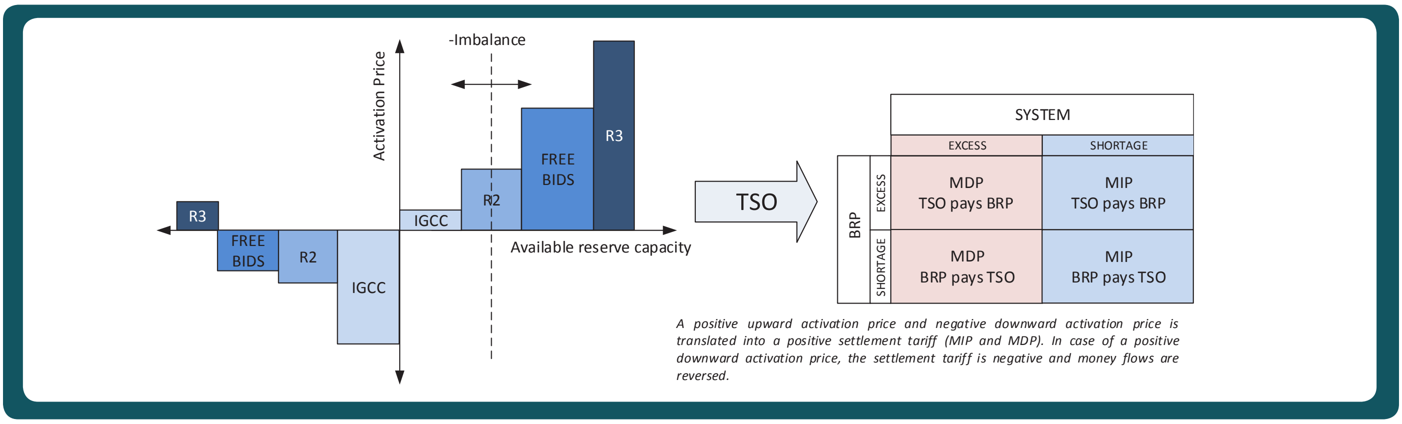

Figure 4: Bid ladders for activating reserve capacity (left): positive (negative) available reserve capacity represents upward (downward) reserve capacity; positive (negative) activation price represents a cash flow from TSO (BSP) to BSP (TSO); downward reserve capacity can be bid at both negative as positive price. Imbalance settlement mechanism (right): MDP marginal decremental price; MIP marginal incremental price

This issue calls for measures in order to create market participation or at least well-functioning prediction models.

The large imbalance requires large amounts of downward reserve capacity to be activated (Figure 7). First, the imbalance is netted with the IGCC after which the available secondary reserve (R2) is activated. This capacity is limited to 140 MW and additional reserve capacity is to be activated resulting from the free bids (Bids-) and the last resort inter-TSO cooperation (R3). However, the free bids are limited and expensive, as downward flexibility remains limited due to the low demand while facing large shares of inflexible generation. This explains the negative imbalance settlement tariffs, resulting from the activation of large amount of downward reserve capacity far in the merit order. As one goes further in the merit order, activation prices increase, which explains the negative prices.

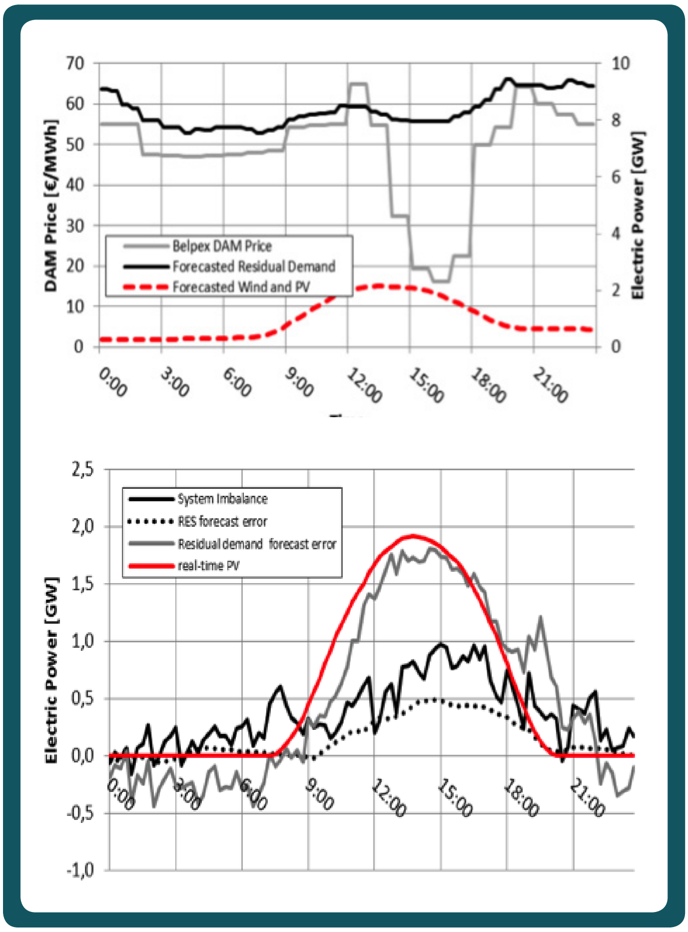

Figure 6: Day-ahead market operation (left) and system imbalance (right) on April 1, 2013

Need for downward flexibility

The intermittency of RES translates into volatile market prices as well as negative prices during periods where high RES-E injections hit a low demand. In the day-ahead market, this is driven by expected injections, while in real-time markets, this is driven by unexpected injections due to prediction errors.

There are three major reasons why one can end up with negative prices on these markets. First of all, high production subsidies result in a distorted price responsiveness of RES-E technologies, i.e. renewable generating units are willing to pay to inject power. Furthermore, a large part of the RES-E currently connected to the distribution system lack control capabilities and right market incentives to react upon negative market prices. Therefore, measures are needed to improve the active market participation of renewable generation and achieve a cost-efficiency and reliable operation of the system.

Second, the negative prices result from the limited flexibility of the conventional power plants. This may result from technological limitations such as start-up, shut-down and output ramping constraints. Negative prices induce flexibility on the short- and long-term by means of incentivising the output control of must-run conventional generation sources, e.g. nuclear power, or the reduction of minimum run levels of power plants, e.g. CCGT. Furthermore, these negative prices may facilitate implementation of new sources of flexibility such as demand-response or storage technologies.

Finally, negative prices occur from must-run conditions of conventional power plants in order to meet system security standards. A major challenge is the increasing need of reserve capacity to balance the prediction errors of RES-E. It is therefore important to counter this need with improving forecast tools, or optimal sizing and allocation methodologies. Furthermore, it should be investigated how an increasing share of the reserve services can be provided with alternative technologies such as storage, demand response, or RES.

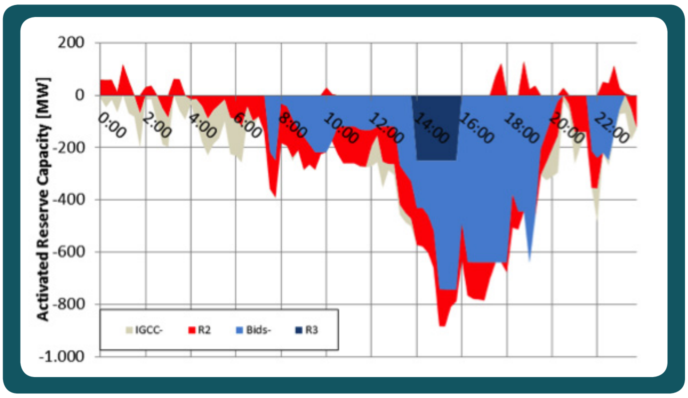

Figure 7: Upward (positive) and downward (negative) regulation volume on April 1, 2013

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